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KENTUCKY WEST VIRGINIA GAS COMPANY

PROGRESS REPORT
EXPERIMENTAL STIMULATION OF THE
DEVONIAN SHALE FORMATION ON
WELL NO. 7239

CONTRACT NO. E (46-1)-8000
DATE DECEMBER 30, 1975

PREPARED BY

KENTUCKY WEST VIRGINIA GAS COMPANY
GEOLOGICAL STAFF

Kentucky West Virginia Gas
Prestonsburg, Kentucky

Address Correspondence to:
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December 30, 1975

U. S. Energy Research & Development Administration
Morgantown Energy Research Center
P. O. Box 880
Collins Ferry Road
Morgantown, West Virginia 26505

Attention: Mr. W. K. Overby, Jr.

Re: November Progress Report
Contract No. E (46-1) 8000

Gentlemen:

I am submitting the monthly technical report which covers the stimulation phase on Well No. 7239 - Nicholas Combs located in Perry County, Kentucky. This well was drilled under the terms set out in Contract No. E (46-1) 8000.

This report is presented in three sections:

1. Experimental Stimulation
2. Stimulation Events
3. Exhibits - which include Mineral Management's initial completion report.

The stimulation phase of the program went much as planned with only minor problems occurring but the net results obtained after stimulation were discouraging.

Thus far the Company has not received Mineral Management's final report on the four stage Foam Frac. This report will be forwarded to you as soon as it is received.

Very truly yours,

E. B. Jenkins

Chief Geologist

Attachments

CC: Mr. F. O. Christie, Jr. (1 copy)
Oak Ridge Operations

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KENTUCKY WEST VIRGINIA GAS COMPANY

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EXPERIMENTAL STIMULATION OF THE
DEVONIAN SHALE FORMATION ON
WELL NO. 7239

ERDA CONTRACT
E (46-1)-8000

INTRODUCTION

Kentucky West Virginia Gas Company submitted a detailed report July 28, 1975, covering drilling, coring and logging on Well No. 7239 located in Perry County, Kentucky. Analysis from the core and electric log data was studied and resulted in the selection of four zones for experimental treatment on the Devonian Shale. This report details the design and implementation of the experimental stimulation.

TREATMENT DESIGN

Mineral Management Inc., Denver, Colorado was selected to design and supervise the stimulation of the Devonian Shale formation on Well No. 7239, using their Foam Frac[R] Method. The Foam Frac is basically made up of surfactants, water and nitrogen blended into a foam for the sand carrying agent. The advantages of the Foam Frac over a conventional water frac are listed as the following:

1. Greater frac area is created with less water.

2. Formation damages is reduced because less water is inoculated into the Shale formation.

3. Clean-up time is shortened by the return of the nitrogen and because of the use of less fluid.

Mineral Management designed the Foam Frac stimulation for the four (4) zones selected by ERDA and Kentucky West Virginia Gas Company personnel. These zones were 2368-2402'KB; 2410'-2495' KB; 2500'-2575' KB; and 2585'-2680' KB. Stimulation would proceed from the bottom Shale zone upward.

The detailed design work and subsequent supervision of the treatments were done by Herschel Vaughn of Minerals Management, Inc. A copy of Mr. Vaughn's proposals is included with this report. See Exhibit I.

WELL PREPARATION

At the completion of drilling Well No. 7239, 4 1/2-inch casing was set through the Devonian Shale and cemented across the entire Shale section. A small pay encountered in the Big Lime formation was cemented through in a second stage cement job. This Big Lime pay will be fractured in the event of a dry hole or a marginal producer in the Shale.

On October 27, 1975, Oliver Jenkins Drilling Company moved a 28-L Bucyrus completion rig over the well. The rig proceeded to drill out the D.V. cement stage tool and clean out the well to total depth.

CEMENT EVALUATION

Allegheny Nuclear Surveys, Inc. ran a Cement Quality Log to evaluate the cement behind the 4 1/2-inch production casing. The log interpretation indicated good quality cement throughout all zones of interest in the Devonian Shale, and the cement top was at 2150'. A copy of the cement log is attached as Exhibit II.

WELL TREATMENT

As stated, the Shale section was separated into four zones, with each zone designed to be fraced in a separate stage. Perforations for each were modified for individual zone application. Each stage was designed to be cleaned up and the flow potential measured and evaluated before proceeding to the succeding stage.

First Stage Frac

The basic design for the first stage was to be a pump rate of 35 BPM, 75 quality foam, and 47,000 pounds of 20/40 mesh sand through ten perforations. These perforations were to be 0.41-inch diameter holes placed at the following depths: 2604'-2614' (5 holes), 2649'-2675' (5 holes). The well-head fracturing pressure was calculated to be 1369 psig, assuming bottom hole fracturing pressure of 1000 psig and that all perforations were open. Designs on subsequent zones could be modified pending on the results of implementing the first stage.

The first stage frac was completed much as designed, with only minor mechanical difficulties encountered in the pumping equipment and pressure measuring devices. The recorded pressures were lower than anticipated but this was discovered later to have been caused by malfunctioning pressurer recorders which were showing lower than actual pressures. The foam quality was 69% rather than the designed 75%. This difference was caused by a higher water injection rate than was shown on the barrel counter. These equipment controls were corrected before the second stage frac was initiated.

In flowing back the first stage, the foam produced at the well head was much too stable and apparently did not break back as designed. As a consequence, fluid recovery from this first stage was much less than anticipated. This stable foam in the formation probably restricted the flow of gas to the well bore.

At one point gas from the first zone gauged at 47 MCFD, part of which was probably nitrogen. This gas production varied from 0 MCFD to 47 MCFD, depending on the height of the fluid in the well bore.

A day-by-day account of procedures for each stage is included within this report. See Section <u>II</u>.

Second Stage Frac

A Go, International frac-over plug was set at a depth of 2590' to separate the first and second stage fracs. The sealing ball was pumped down with 250 gallons of 15% mud acid and a positive seal was obtained on the plug. The zone was perforated by Allegheny Nuclear with 10 perforations at the following depths: 2519', 2522', 2526', 2543', 2550', 2560', 2565', 2572', 2575', and 2578'.

The design of the second frac was basically the same as the first stage, with the exception of using less surfactant to attempt to get a controlled break-back of the foam.

The initial pressure on the second zone was higher than anticipated which indicated that some perforations were not open. Five perf balls were dropped in an attempt to open additional perforations. The pressure chart indicated that some of the perf balls seated and additional perforations were opened. This resulted in the well head pressure being lowered approximately 200 psig.

This stage was completed much as designed, although the total volume of fluid and sand was less than anticipated due to the amount of nitrogen expended intially on the ball-out procedure.

The foam produced from this zone after the frac was much less stable than the first zone, indicating a better down-hole break-back. Approximately 70% of the fluid injected in zone two was recovered resulting in a much better clean-up.

At this time 2-inch tubing was run into the well with a stinger installed on the bottom to separate the first and second zones. Before the tubing was stung into the frac-over plug, a small amount of crude oil was swabbed out of the tubing. The well was swabbed several times at this point to clean up any fluid remaining in the bore hole. The tubing was stung into the frac-over plug and the lower zone swabbed through the tubing. Very little fluid was recovered through the tubing and gas was negative from the first zone. The annulus pressure was not affected by swabbing the tubing which indicated no communication between the two zones.

The gas tested approximately 70 MCFD from the casing head which was coming from zone two. Following the testing of zone two, the tubing was tripped out of the hole. A problem of intermittent grabbing and releasing was encountered on the first eighteen joints, then the problem cleared up. This difficulty appeared to be in the vicinity of the D.V. stage tool at a depth of 2045 feet. From the difficulty of pulling the tubing and the forementioned appearance of oil in the hole, it was theorized that the D.V. tool had by some unexplained reason become open. After the tubing was tripped, the frac-over plug was drilled out and preparations made to test the 4 1/2-inch production casing.

A Halliburton Speed-E-Line bridge plug was set at 2502' and the casing pressured up to determine if a leak existed. This test showed a casing leak. McCullough Services was employed to run an Iridium - 192 Liquid Tracer to pinpoint the casing leaks. They proved the fluid to be leaving through the DV stage tool. This leak was repaired by squeezing 25 cubic feet of neat cement. After the cement cured, the hole was cleaned out to the bridge plug set at 2502'.

Third Stage Frac

The third stage was perforated with 10 jets at the following depths: 2419', 2423', 2427', 2444', 2449', 2454', 2469', 2475', 2484', and 2488'. The first gun interval (2469 to 2488) when fired increased the gas from 0 MCFD to 39 MCFD which indicated either (a) possible communication between the lower zones and zone three, or (b) penetration of a gas pay by the perforations. At this time there was no practical way to distinguish between the two above possibilities. Therefore, it was decided to proceed to frac zone three and determine from the formation breakdown if communication had been established with the lower zones.

Due to the problems encountered with the D.V. stage tool, it was decided to treat zone three through tubing to protect the squeezed area. A string of two-inch tubing was installed in the well with a Baker tension packer at the base, and the annulus was loaded with water.

The third stage frac was re-designed to allow for greater friction pressure generated by treating through tubing. The design was for a surface pressure of 3700 psig and a pump rate of 25 BPM.

The formation breakdown pressure was higher than calculated which indicated no communication between zone three and the lower zones. Five perf balls were pumped into the well to obtain maximum breakout perforations. The perf balls were removed from the perfs. Actual treating pressure and injection rates were close to that predicted. The total sand used in this stimulation was less than originally planned due to the amount of nitrogen expended in balling out.

Ten (10) millicuries of radioactive tracer sand was run with this treatment to attempt to determine the extent of the fracture.

After approximately 125 barrels of fluid was recovered on cleanup the gas gauged 50-60 MCFD. Recall approximately 40 MCFD of this gas was present before fracturing. After the flow test was completed, the two-inch tubing was pulled from the well and the Halliburton bridge plug was drilled out and pushed to bottom without incident. There was no apparent pressure buildup under the plug.

A gamma-ray tracer log-run at this time indicated the frac stayed within the zone of interest. However, there was some indication of down hole migration of the tracer sand, but this migration did not indicate communication with the lower zones. A copy of the tracer log is included in this report. See Exhibit III.

It was decided at this time to pressure test the casing to determine if the squeezed cement in the D.V. stage tool zone would stand the treatment pressures calculated for the fourth stage frac. A Halliburton Speed-E-Line bridge plug was set at 2410' and the casing pressured to 1900 psig. The test pressure indicated an effective seal on the squeezed area at the D.V. tool. It was decided that the fourth stage frac could be performed through the casing.

Fourth Stage Frac

The fourth stage frac design was much the same as the first and second stages. The calculated pressure was 1300 psig with an injection rate of 35 BPM. Ten perforations for the fourth stage were placed at the following depths: 2326', 2330', 2335', 2363', 2368', 2373', 2378', 2383', 2388', and 2393'. Initial treating pressures were higher than anticipated on this zone. Following the techniques used in previous zones, five (5) perf balls were dropped to assure opening of additional perforations. The sand concentration was increased to a maximum of nine (9) pounds (10/20 mesh sand) per gallon on surface or the equivalent of two (2) pounds per gallon at the perforation entrances. This was the highest sand concentration attempted during the four treatments. Tracer sand was run on this zone to determine the vertical extent of the induced frac.

On cleanup, after 136 barrels of fluid had been recovered, gas gauged 61 MCFD.

The bridge plug was drilled out without incident and no evidence of pressure buildup was found underneath the bridge plug as previously anticipated. A gamma-ray tracer log showed the frac stayed within the zone of interest' however, it indicated that the three (3) perforations in the Sunbury Shale possibly did not take any of the fracture treatment. This completed the mechanical phase of the stimulation program.

TESTING

Upon completion of the planned stimulation program, the tubing was re-installed in the well to a depth of 2662'. The well was alternately blown and swabbed for a number of days to obtain a removal of remaining frac fluid. The gas from all four (4) zones are combined into one gas stream, and the total open flow on all four gas zones gauged from 42 MCFD to 49 MCFD. It was determined that the blowing gas energy could remove the small amount of returning frac fluid, so the completion rig was released December 8, 1975.

The well was shut in and the surface pressure at the well head gauged 260 psig in 48 hours. This pressure was approximately 220 psi lower than other completed Shale wells shut-in pressure in this immediate area. The well has been blown periodically since this time for short durations to remove remaining frac fluid from the bore hole.

CONCLUSIONS

Well No. 7239 had a total of 14 MCFD open flow from the Devonian Shale upon completion of drilling operations. At the date of this report, the well has tested a total of 42 MCFD from the four stimulated zones, or only an increase of 28 MCFD. It is hoped that this flow potential will improve after a series of short flow cleanup periods to remove remaining frac fluids.

This report is primarily concerned with detailing the design and implementation of stimulating Well No. 7239; however, the following points can be drawn from preliminary analysis of the results.

1. The mechanics of Foam Fracturing can be designed and implemented with a rather high degree of accuracy. The Foam Frac will tolerate and carry a large concentration of frac sand into the formation.

2. The nitrogen used as an ingredient in the Foam Frac is an effective aid in cleaning the Devonian Shale well after stimulation.

3. The surface pressure on Well No. 7239 is low compared to other Shale wells in the area. Possibly formation damage and frac fluid fill up in the bore hole account for this low pressure.

4. The Devonian Shale in Well No. 7239 has not responded successfully to the Foam Frac stimulation when compared to other Shale wells in this area stimulated by conventional water fracs.

RECOMMENDATIONS

The results obtained in stimulating the Devonian Shale in Well 7239 are disappointing and are certainly below what can be considered commercial or economical. However, this is a research program and deserving of additional tests and studies; therefore, the following recommendations are suggested:

1. The core data should be further investigated to determine the effects of exposure to similar fluid used in frac programs. Special emphasis should be placed on chemical studies of possible clay swelling or any other type damage that may occur.

2. If the chemical analysis indicates formation damage then special studies should be placed on chemical control of such damage in future stimulation designs.

3. Bottom hole pressure tests should be made on Well 7239 in an attempt to determine and explain the low surface pressure. Also isochronal flow tests should be made to project possible delivery performances of this well.

*4. Well 7239 should be connected to the pipeline system and placed on delivery. The production results should monitored closely for six months and if the results are extremely poor, which is suspected, then the well should be released to the Company for completion of the Big Lime zone. If this is not successful then the well should be plugged.

*NOTE: A meter has been set to measure the gas from this well and large parts of the pipeline have been constructed. This work has been halted temporarily due to coal operations which have disrupted and taken out of service some 2000' of the gathering line in this area.

COMMENTS

The engineering and mechanical performances of stimulating Well 7239 can be considered a success. The program went for the most part as planned with no insurmountable problems being encountered. However, as often experienced in industry, many geological and engineering successes do not always turn out to be economically feasible, and based upon open flow potential to date, this well can be placed in this category.

There remains much evaluation work on the program by ERDA personnel, and concievably through these studies a technological breakthrough may be achieved which will enhance recovery of gas from the Devonian Shale.

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SECTION NO. II

STIMULATION EVENTS

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STIMULATION EVENTS - Sect. No. II

WELL NO. 7239

10-27-75 Move work over rig on location

10-28-75 Rig up. Drill out Halliburton D.V. cement stage tool. Clean hole to 2697' PBTD. Dump fresh water and swab dry. Hole clean.

10-29-75 Load hole with fresh water and run Allegheny Cement Quality Log. Cement log indicated good cement. Cement tops First stage - 2150' , Second Stage - 1838'. D.V. stage tool 2034-2036. (Allegheny log records one (1) foot higher than Schlumberger open hole log. This variance in footage will change at different depths due to mechanical changes in logs from heat generated in copying the logs.) Open hole wash out - 2498'-2516' - Poor cement

Swab hole to 2300' to lessen hydro-static head on Devonian Shale before perforating. Had slight show of gas ahead of swab. Ran Allegheny High Resolution Thermometer to locate point of gas entry. Log inconclusive due to water, which was left in collars while swabbing, dripping down hole. Decision made to go ahead with perforations. Probably slight collar leak.

Perforated with 3 1/8" hollow steel carrier gun, with ten (10) Densi-Jet, .41" diameter shots at the following depths: 2606', 2608', 2610', 2612', 2614', 2649, 2653, 2657, 2661', 2665'

Swab hole dry to 2697' PBTD. Well head open to atmosphere. No gas

10-30-75 Clean up well. Prepare to Foam-Frac first stage

10-31-75 Install 4 1/2" full open master gate valve (3000 psi test) on casing head

Dump one hundred (100) gal. Dowell regular mud acid.
Foam Frac first stage:

Total Fluid	51,300 gals.
Sand	45,000 lbs. 20/40 mesh
Foam Caulity	.68
Nitrogen	294,488 SCF
	7,818 SCF/min.
Water	350 Bbl. in Treatment
	50 Bbl. in Breakdown
Potassium	3,000 lbs.
Calcium Chloride	200 lbs.
Soap (F52B)	45 gals.

	Pressures Dowell ATR	Dowell Martin-Decker	Ky. W. Va. Gas Recorder
Break	950 PSI	1250 PSI	
After Break	500	525-550	
Frac Press.	950	2150-1300	
After Frac	500	625	670

Immediate shut in - (Dowell ATR) - 900 psi
Avg. Treating Press.(Dowell ATR) - 950 psi

FIRST STAGE FLOW BACK

Date	Time	Flow Back Time	Choke	Well Head Pressure	Comments
10-31	5:00 pm	0:00	10/64	660	N_2 only - pressure dropping
	5:18 pm	0:18	18/64	530	N_2 only
	5:24	0:24	18/64	450	H_2O to surface - no sand
	5:35 pm	0:35	18/64	240	Good H_2O return
	6:00 pm	1:00	18/64	140	
	6:20 pm	1:20	18/64	230	Pressure increasing
	7:00 pm	2:00	18/64	320	
	7:30 pm	2:30	18/64	370	N_2 & H_2O - small amount sand
	11:00 pm	6:00	18/64	490	Max. pressure buildup
11-1	7:30 am	14:30	18/64	175	Pressure drop constant
			26/64	Change choke.	N_2 & H_2O small amount sand
	8:00 am	15:00	26/64	100	Liquid recovery - 100 bbls.
	10:00 am	17:00	18/64	20	N_2 & H_2O large amt. sand - change choke
	11:00 am	18:00	18/64	40	
	5:00 pm	24:00	18/64		Liquid since 10 pm - 20 bbl. approx. 150 bbl. back. Approx. 20 sand back. N_2 & H_2O - small amt. sand returning.

		24:00	46/64	20	Change Choke
11-2	7:00 am	38:00	46/64	0	Flow liquids by head. Gas will bu: Estimate gas at less than 20 MCFD. Liquid recovery last 13 hrs. - 23 Bbls.. Total Liquid Recovery - 17 Bbls. - Total Sand Recovery - appr 400#

11-2-75 Check sand for fillup in casing with bailer. Thirty-five (35) foot fillup. Cannot bail out. Wait on sand pump. Made approx. 15 bbl. fluid. Sand coming back. Foam very stable. Not breaking back as it should. Shut well in over-night. Gas approx. 20/10 W 1" - 47 M

11-3-75 12 Hrs. shut in - 390 psig

Mix sand in well with clay and stir up with tools. Bail sand out to T.D.. Approx. 200 bbl. fluid back at this time. Shut well in overnight. Gas - slight show.

11-4-75 12 hrs. shut in - 350 psig. Shut well in and flow No sand. Very little fluid. Run swab. Shut well in overnight. Gas - not enough to gauge.

11-5-75 12 Hrs. shut in - 330 psig. Blow well off. Producing mostly stiff foam. Sand ha s fillup approx. 1 foot. Leave well open to atmosphere. Not enough to gauge .

11-6-75 Set Go International frac retainer bridge plug by Allegheny at 2590'. Pump sealing ball down with 250 gal. regular mud acid with 5 bbl. water cushion on top of acid.

Allegheny perforated with 3 1/8" hollow steel carrier gun with 10 - .41" Densi-Jets at the following intervals: 2519', 2522', 2526', 2543', 2550', 2560', 2565', 2572', 2575, 2578'

Calibrate Dowell ATR and Martin-Decker Recorder to dead weight gauge. Foam frac second stage.

Average Injection Rate	32.9 BPM
Average inj. Rate - Water	8.5 BPM
Average Inj. Rate - Nitrogen	9030 SCFM
Average Treating Pressure	1569 PSIG
ISIP	900 PSIG
Total Fluid	47,000 Gals.
Frac	293 Bbls. Water
Breakdown	58 Bbls. Water
Flush	41 Bbls. Water
Total Nitrogen	361,000 SCF
Total Soap	30 Gals.
Soap Injection	1.75 Gals./1000
Perf Balls	5
Total Sand	29,000 lbs. - 20/40/sand
	7,000 lbs. - 10/20 sand
Calcium Chloride	400 lbs.
Potassium Chloride	7,000 lbs.

FLOW BACK - SECOND STAGE

Date	Time	Flow Back Time	Choke	Well Head Pressure	Comments
11-6	4:00 pm	0:00	18/64	690	H_2O & N2 to surface
	5:00 pm	1:00	24/64	500	H_2O, N_2 and small amt. sand
	6:30 pm	2:30	18/64	300	N_2, H_2O and large amount sand, (approx. 300 bbls.)
	7:00 pm	3:00	18/64	550	N_2, H20 and small amt. sand
11-7	9:00 am	17:00	48/64	160	Change chokes. Attempt to unseat frac ball.
	12:00 am	20:00	48/64	0	Well blown down. Did not unseat ball.

11-7-75 Well open to atmosphere. Flowing water and foam. Foam breaking back better than first stage. Approx. 180 bbls. fluid recovered. Shut well in and let pressure build to 180 psig. Attempt to blow ball out of frac-over plug. Ball will not come out. Rig up tools and fish out ball. Retrieve frac over ball and four perf balls. Perf balls did not indicate that they had seated. Gas at this time gauged 40 to 50/10 W 1" 66 to 74 MCFD. Swab well approx. 15 bbl. fluid back. Leave open overnight.

11-8-75 8:00 a.m. - Gas Gauged 30/10 W 1" - 58 MCFD. Well flowing foam intermittendly (approx. 3 to 5 gal. each time) Swab well to 2200'. Recover approx. 10 bbl. fluid - No sand coming back. Run 2" tubing to 2' - 3' above frac over plug with stinger on tubing. Swab tubing until dark. Very little fluid recovery. Head pressure picked up to 130 psig. shut well in overnight.

11-9-75 8:00 a.m. Tubing Pressure - 390 PSIG
Head Pressure - 350 PSIG

Blow tubing in tanks. Recover approx. 10 bbl. fluid. Leave well open.

4:00 p.m. - Gas 20/10 W 1" - 47 MCFD - Shut well in overnight.

11-10-75 6:00 a.m. Tubing Pressure - 250 PSIG
Casing Head - 275 PSIG

Open well to tank and recovered approx. 2 bbl. fluid. Well blew down in one hour. Recovered slight stain of oil. Start swabbing tubing with casing head at 175 psig. Run swab to 2588' Pressure in casing dropped to 100 PSIG and held steady. Liquid recovered was black, water cut crude oil. Estimated recovery - 3 bbl. water and approx. 1/2 bbl. crude oil. Crude was extremely black, fairly viscous. (Checked sample of crude oil at Prestonsburg office - 32° API @ 60°F or sp. gr. of .8633. This crude is not a typical Big Lime Crude oil.)

Sting tubing into frac retainer plug and swab lower zone with upper zone shut in. Casing pressure built to 75 psig, and was not affected by swabbing of lower zone, (indicating there was no communication between zones). Liquid recovered from lower zone mostly water, slightly foamy and very slight cut of oil. Tested gas from both zones through a 1" opening.

Gas from the lower zone was completely dead. The upper zone stabilized at 40/10 W 1" - 67 MCFD on approx. a two hour test.

Pulled stinger out of frac retainer and tripped tubing. Tubing hanging every 30' for the first 18 joints (tubing would hang then jump free.) All tubing out of hole at 4:30 p.m. The bottom 18 collars showed evidence of hanging on some object. Tubing tally indicated problem area to be in vicinity of the cement DV stage tool.

11-11-75 Rig up drilling string and start to spud on frac retainer plug. Plug drove 2' to 2592' in first 15 minutes. Retainer released at 3:15 p.m. and was driven down hole to 2686'. Fillup with retainer and frac sand is 11 feet. Continue to drill on plug. Jars on drilling string unscrewed and left in hole. Run in hole and fish out on first trip. Cannot push plug below 2686'. Left well open overnight. Decide to set bridge plug at 2502' and test casing for leak.

11-12-75 Swabbed casing and recovered 1 to 2 bbls. of black crude oil. Allegheny Nuclear Surveys set Halliburton Speed-E-Line bridge plug at 2502'. Rig up Dowell cementer and pressure up on casing. Casing leaking at approx. 1000 psig and at 5 BPM. This pressure indicates a small leak. If D.V. tool were wide open pressure would be much less. Release Allegheny and wiat for McCullough to run liquid isotope tracer.

11-13-75 McCullough ran Iridium 192 and Liquid Isotope Injection Log, which indicated fluid leaving the casing at the D.V. stage tool and traveling down the outside of the casing. Traced fluid down to 2053'. Could not move any further at 5 BPM. No indication of Movement of fluid below the DV tool inside the casing.

Rig Dowell up to squeeze cement DV tool. Pumped 25 cu. ft. of Class A cement with 2% $CaCl_2$. Pumped plug to 1825' at 3 BPM and 700 PSIG and shut down for 3 minutes (6 cu. ft. in formation) Pumped plug to 2000' at 1 BPM and 650 PSIG and shut down for 15 minutes (23 cu. ft. in formation). ISIP was 500 psig. Pump plug to 2026 at 1 BPM and 650 PSIG. ISIP - 500 PSIG. Shut down for 12 hours.

11-41-75 Drill on cement plug. No cement in pipe at 2040' at D.V. tool. Tools go to 2490' (12' fillup on top of plug at 2502'). Drill to 2498'. Leave 4 feet fillup on top of plug.

Dowell dump 100 gal. regular mud acid with 5 bbl. water cushion on top. Allegheny perforate third zone with 3 1/8" hollow steel carrier gun with 10 - .41" Densi-Jets as follows: 2419', 2423', 2427', 2444', 2449', 2454', 2469', 2475', 2484', 2488'

First gun shot covered interval from 2469' - 2488' At this time gas increased from 0 MCFD to approx. 39 MCFD, indicating possible communication with the second frac zone. Checked the plug at 2498' and apparently was holding. Communication possible outside the 4 1/2" casing. Finished perforating casing and arranged for McCullough to run radioactive tracer sand on the third stage frac. Ran 2-inch tubing on Baker packer to 2332'. Load annulus with water (18 bbl.) Gas from tubing 14/10 W 1" 39 MCFD. Left well open to atmosphere.

11-17-75 Prepare to Foam Frac third stage. Nitrogen truck broke down. Wait until 11-18-75 to frac. Minerals Management needs to re-design frac for 25 BPM and 3600 PSI. Dowell change pump to E-Head pump to allow for extra pressure. Annulus between tubing and 4 1/2" casing full, indicating packer and squeeze job on DV tool is holding.

11-18-75 8:00 a.m. Prepare to frac. Dowell E-Head pump leaking. Send fornew O-rings. 11:00 a.m. Repairs complete. Pump in 100 gal. regular mud acid. Start frac with sand. Pressure too high. Drop 5 perf balls - shut down to allow perf balls to drop off of formation. Wait 30 minutes, continue frac.

FOAM FRAC - THIRD STAGE

Average Injection Rate	23.4 BPM
Average Inj. Rate - Water	4 BPM
Average Inj. Rate - Nitrogen	7150 SCFM
ISIP	300 PSIG
Average Treating Pressure	3700 PSIG
Total Fluid	44,000 Gallons
Frac	
Breakdown	
Flush	
Total Nitrogen	324 SCFM
Total Soap	
Soap Rate	2.5 Gal./1000 gal.
Foam Quality	.83
Perf Balls	5
Total Sand	20/40 - 29,000 lbs.
	10/20 - 7,000 lbs.
	10 MC RA Sand
Calcium Chloride	400 lbs.
Potassium Chloride	7,000 lbs.

FLOW BACK - THIRD STAGE

Date	Time	Flowback Time	Choke	Wellhead Pressure	Comments
11-18	4:30 pm	0:00	18/64	320	Start flow back
	5:30 pm	1:00	18/64	600	N_2, small amounts green foam - choke plugged
	6:00 pm	1:30	18/64	670	N_2, small amounts H_2O large amount of sand, flow back tee downstream. Let flow to clean up sand
	6:30 pm	2:00	10/64	750	Repaired flowback line. Sand decrease Estimate 400 lbs. sand bac,
	7:00 pm	2:30	10/64	690	N_2 only
	8:00 pm	3:30	10/64	670	N_2 with small amount H_2O fluid returne 15 bbl.
11-19	7:30 am	15:00	18/64	440	Change choke - water returned 16 Bbl.
	12:00 Noon	19:30	18/64	220	N_2, white milky H_2O and small amt. sa Fluid returned - 34 bbl.
	4:30 pm	24:00	18/64	120	N2, gas and H_2O - no sand. Fluid ret 55 bbls.
11-20	9:30 am	41:30	18/64	50	N_2, gas and small amt. H_2O Fluid recovered - 98 Bbl.

Flow well to atmosphere. Approx. 125 bbl. recovery. Ralease packer - 18 bbl. annualr fluid dropped to bottom. Attempt to swab out. Recover raw acid. Cannot swab through tubing due to acid. Pull tubing & clean up hole. Swab from 2300'. Pulling 200' - 200' of foam with gas. Gas gauging 50-60 MCFD. Shut in pressure buildup.

11-21-75 8:00 a.m. Casing pressure - 230 psig. Blow well to atmosphere and swab casing to 2300' KB. Small amount of water and foam recovered. Gas estimated at less than 50 MCFD. Drill on Halliburton bridge plug at 2502' at 11:30 a.m. Bridge plug probably drilled up before releasing. There was no indication of pressure buildup when the packer was knocked loose. Pushed remainder of plug down hole at 2:15 pm. Plugged stopped at 2647' above lowest 5 perforations of the first zone. Water and foam level increased in the well bore at this time. Possibly was pressured up under the plug and was produced into the well bore when the plug was released. Drilled and bailed to 2644' and left open.

11-22-75 Swabbed casing from 2350' between 9:00 and 10:00 a.m. Recovered 300'-400' of foam each trip. Drilled and bailed sand to 2681'. Allegheny Nuclear Surveys ran Gamma-Ray from 2680' to PBTD to trace placement of the radioactive sand during the treatment of the third zone. Log indicates treatment was placed in the entire perforated interval with some migration down the hole. Set Halliburton Speed-E-Line bridge plug at 2410' . Dowell cementer spotted 100 gallons regular mud acid and filled hole with fresh water. Pressured up to 1900 psig surface pressure to test squeeze job on D.V. tool. Pressure holding indicating no fluid migration through the DV tool. Swabbed casing to 2000' and perforated with 3 1/8" hollow carrier gun with 10 - .41" Densi-Jets at the following intervals:

2326', 2330', 2335', 2363', 2368', 2373, 2378', 2383', 2388', 2393'

Left well open and left location. No gas to surface at this time.

FOURTH STAGE FOAM FRAC

Average Injection Rate	31.5 BPM
Av. Inj. Rate - Water	6 BPM
Av. Inj. Rate - Nitrogen	10,350 SCFM
Avg. Treating Pressure	1687 PSIG
ISIP	400 PSIG
Total Fluid	45,000 Gallons
Frac	237 Bbls.
Breakdown	69 Bbl.
Flush	25 Bbl.
Total Nitrogen	348,000 SCF
Total Soap	23.75 GAllons
Soap Rate	2.1 gall/1000 gal.
Foam Quality	0.78
Perf Balls	5
Total Sand	20/40 - 25,000 lbs.
	10/20 - 15,000 lbs.
Potassium Chloride	3500 lbs.
Calcium Chlordie	200 lbs.

Well shut in at 300 PSIG. Wait approx. 1 hour until equipment is removed and choke and flow line installed.

2:00 p.m. open well to tanks. Well on vacuum

FLOW BACK - FOURTH STAGE

Date	Time	Flowback Time	Choke	Wellhead Pressure	Comments
11-23	2:00 pm	0:00	10/64	20	Pressure dropping on vacuum
	3:00 pm	1:00	10/64	0	Vacuum
	4:30 pm	2:30	10/64	0	Small flow - N_2 only
	5:30 pm	3:30	18/64	20	N_2 and H_2O - no foam
	6:30 pm	4:30	18/64	210	N2 and H20 - no foam
	7:00 pm	5:00	18/64	480	N2 and milky white H20 No sand recovered 22 bbl. H20
	7:30 pm	5:30	18/64	620	Max. recorded pressure
	8:30 pm	6:30	18/64	580	N2 and H20 - No sand
11-24	10:30 am	20:30	48/64	100	N2 and H20 - 92 bbl. H20 recovered. Change 18/64 to 48/64
	11:30 am	21:30	48/64	10	N2 and H20 101 bbl. H20 recovered
	2:30 pm	24:30	48/64	0	110 Bbls. H20 recovered. Disconne flow line and tagged sand at 2391'
11-25	9:00 am	43:00	48/64	0	136 bbl. H20 recovered - gas gauge 34/10 W 1" 61 MCFD

Blow and swab well. Very little fluid recovered

2:00 pm - Clean out sand, start drilling on bridge plug
4:30 pm - Bridge plug at 2676' - call for Allegheny to run Gamma-Ray Tracer
8:30 pm Allegheny on location. Run Gamma-Ray tracer log to trace radioactive sand on fourth stage frac. Indications are little or no migration of frac to third zone frac. Perforations in Sunbury Shale from 2326' to 2336' probably did not take any frac fluid. T.D. at 2679.

11-26-75 Run 2" tubing at 2662'. Attempt to swab tubing. Cannot get past 9th joint of tubing. Shut well head in, leave tubing open. Shut down for Thanksgiving.

11-28-75 Well checked by foreman. Foam under rig floor indicating well had flowed. Wellhead pressure at 30 psig. Well head built up to 130 psig.

11-29-75	Checked by foreman. Well had flowed some foam since 11-28-75. Well head at 115 psig.
11-30-75	Well checked by foreman. Well had flowed some foam. Shut well in overnight.
12-1-75	18 Hr. 170 psig. Blow well off. Flow some foam and water. Pickup tubing, remove bad tubing joint, run back to 2662' Swab well through tubing. Recover approx. 2 bbl. fluid. Gas 22/10 W1" 40 M= with head and tubing to atmosphere.
12-2-75	Swab tubing to bottom. Approx. 2 bbl. fluid out. 1 1/2 hr. open flow - 16/10 W 1" - 42 M - Leave well open. Send rig crew home.
12-4-75	Head pressure - 130 psig. Well head flowed some foam out by itself. Pressure tubing from head and let tubing flow, probably 1 bbl. fluid recovered. Gas 16/10 W 1" - 42 M Shut well in.
12-5-75	No check
12-6-75	Head and tubing 49 hr. 260 psig. Blow well about 1 hr. - 1 bbl. water. Shut well in.
12-7-75	Head and tubing - 48 hr. - 260 psig. Blow well about 30 min. 20 gal. water. Shut well in.
12-8-75	18 Hr. 2" tubing had 170 psig and casing head 195 psig. Well was blown for a few minutes to determine that the well would blow.

<u>SECTION NO. III</u>

EXHIBITS

EXHIBIT NO. 1

MINERALS
MANAGEMENT INC.
SUITE 1810, LINCOLN CENTER BLDG.
1660 LINCOLN STREET
TELEPHONE (303) 573-7561
DENVER, COLO. 80203

October 17, 1975

Mr. Charles A. Komar
Project Leader
Stimulation of Oil
and Gas Reservoirs
Morgantown Energy
and Research Center
Collins Ferry Road
Morgantown, West Virginia 26505

Dear Mr. Komar:

Re: FOAM-FRAC[R]
Kentucky West Virginia Gas
#7239
Nicholas-Combs Lease
Hazard Field
Perry County, Kentucky

The following is an initial completion report concerning the above mentioned well. This report may be used as additional input for any subsequent planning in the stimulation of shale sequences at 2368-2402'KB, 2410-2495'KB, 2500-2575'KB and 2585-2680'KB.

The 300^{+} foot difference in elevations of the total gross interval will not have a major effect on design or well head pressure predictions. Therefore, I have concerned mysalf with presenting various aspects of treatment design and have enclosed my recommendations for treating the lowest interval at 2585-2680'KB.

Our proposed frac job is a 44,500 gallon, 75 quality foam treatment pumped at 35bpm with 47,000 # of 20/40 sand. Assuming the resulting fracture is vertically oriented, 60 to 70 feet high, and Young's modules of elasticity at 4.39+E6psi, the calculated penetration of the shale sequence is 1800-2100 feet and should realize a calculated productivity ratio of 8.3.

The proposed pumping schedule is:

1. 4,000 gal. pad
2. 2,000 gal. @ 0.5 ppg.
3. 2,000 gal. @ 1.0 ppg.
4. 35,000 gal. @ 1.25 ppg.
5. 1,500 gal. flush

The estimated surface treating pressure thru 4.5 inches, 10.5# casing is 1400 psig, assuming 1000 psig bottomhole treating pressure and 200 psid drop across 12-0.42 inch perforations.

The estimated cost of this treatment, excluding acid and my personal out-of-pocket expenses is $10,000 and includes the following:

Dowell	$6,000
Aircowell	$3,200
MMI (fee)	$ 800

The invoice of Minerals Management, Inc., will include a Foam-Frac fee with a minimum daily field supervision charge plus out-of-pocket expenses. The fee is $600 plus 7.5% of Dowell's and Aircowell's final invoice over $6,000. The entire schedule is included with this letter. The minimum field supervision rate is $225 per day. Estimated out-of-pocket expenses will include $130 airfair and approximately $20/day car rental, $20/day motel plus food.

The completion of all four zones should take 13 days if only minor problems should occur. I recommend an AFE of 17 to 20 days to account for all but major mechanical problems which may occur.

Additional comments are enclosed with this letter for your information.

I hope that you will find this information beneficial and, should we need additional input please advise.

Sincerely,

Herschel F. Vaughn

Herschel F. Vaughn
Petroleum Engineer
Special Services

HFV/lc
cc: Kentucky West Virginia Gas

PROPOSED FOAM-FRAC[R] SCHEDULE

Kentucky-West Virginia Gas
#7239 Nicholas-Combs Lease
Hazard Field-Perry County, Kentucky

35 BPM Downhole Foam Rate

Incremental Foam Volume (gal.)	Sand Concentration at Blender (ppg)	Sand Concentration in Foam (ppg)	Sand (lbs.)	Incremental Volumes Nitrogen (scf)	Incremental Volumes Water (gal.)	Incremental Time (min.)	Cumulative Time (min.)
4,000	0	pad	0	25,600	1,000	2.72	2.72
2,000	2	0.50	1,000	12,800	500	1.36	4.08
2,000	4	1.00	2,000	12,800	500	1.36	5.04
35,000	5	1.25	43,750	223,800	8,750	23.81	29.25
4 1,500	0	flush	0	9,600	375	1.02	30.27
44,500			46,750	284,600	11,125	30.27	

Summary:

Downhole quality A 0.75
Downhole rate @ 35 bpm
Surface Nitrogen rate @ 9,400 scfpm
Surface water rate @ 8.75 bpm

Foam Volume @ 44,500 gal.
Nitrogen Volume @ 290,000 scf
Water Volume @ 11,125 gal.
Sand 20/40 @ 47,000 lbs.

PROPOSED FOAM-FRAC[R] SCHEDULE

Kentucky-West Virginia Gas
#7239 Nicholas-Combs Lease
Hazard Field-Perry County, Kentucky

44.5 BPM Downhole Foam Rate

Incremental Foam Volume (gal.)	Sand Concentration at Blender (ppg)	Sand Concentration in Foam (ppg)	Sand (lbs.)	Incremental Volumes Nitrogen (scf)	Incremental Volumes Water (gal.)	Incremental Time (min.)	Cumulative Time (min.)
4,000	0	pad	0	25,700	1,000	2.14	2.14
2,000	2	0.50	1,000	12,800	500	1.07	3.21
2,000	4	1.00	2,000	12,800	500	1.07	4.28
35,000	5	1.25	43,750	224,700	8,750	18.73	23.01
1,500	0	flush	0	9,600	375	0.80	23.81
44,500			46,750	285,600	11,125	23.81	

Summary:

Downhole quality @ .75
Downhole rate @ 44.5 bpm
Surface Nitrogen rate @ 12,000 scfpm

Surface water rate @ 11.1 bpm

Foam Volume @ 44,500 gal.
Nitrogen Volume @ 290,000 scf
Water Volume @ 11,125 gal.

Sand 20/40 @ 47,000 lbs.

PROPOSED FOAM-FRAC[R] SCHEDULE

Kentucky-West Virginia Gas
#7239 Nicholas-Combs Lease
Hazard Field-Perry County, Kentucky

59 BPM Downhole Foam Rate

Incremental Foam Volume (gal.)	Sand Concentration at Blender (ppg)	Sand Concentration in Foam (ppg)	Sand (lbs.)	Incremental Volumes Nitrogen (scf)	Incremental Volumes Water (gal.)	Incremental Time (min.)	Cumulative Time (min.)
4,000	0	pad	0	25,500	1,000	1.61	1.61
2,000	2	0.50	1,000	12,800	500	.81	2.42
2,000	4	1.00	2,000	12,800	500	.81	3.23
35,000	5	1.25	43,750	223,200	8,750	14.12	17.35
1,500	0	flush	0	9,600	375	.61	17.96
44,500			46,750	283,900	11,125	17.96	

Summary:

Downhole quality @ .75
Downhole rate @ 59 bpm
Surface Nitrogen rate @ 15,800 scfpm
Surface water rate @ 14.75 bpm

Foam Volume @ 44,500 gal.
Nitrogen Volume @ 290,000 scf
Water Volume @ 11,125 gal.
Sand 20/40 @ 47,000 lbs.

RECOMMENDED COMPLETION PROCEDURE

First Day

A. Rig up service unit.

B. Run cement bond log from PBTD to surface, if warranted.

C. Prepare well for perforating.

1. Check PBTD with sinker bar and jars and flag sand line.
2. Swab casing to PBTD.
3. Spot 100 gals.-150 feet of 7% HCL acid over zone of interest at 2585-2680'KB.
4. Spot 200 gals.-300 feet of water on top of acid to clean perforator's wireline.

D. Perforate.

1. Run gamma-ray, casing collar log for depth control.
2. Perforate selectively for limited entry. The number, size, and depth of perforations have not been determined.
3. Hollow carrier gun recommended.
4. Capsule jet perforating charges are recommended.
5. 0.42 inch diameter perforations are recommended over 0.38 inch because of better stand-off.
6. Positive location of perforations will probably not be able to be located by running the CCL, however, it should be re-run and recorded for records.

D. Shut in well for pressure build-up.

Second Day

A. Check and record well head pressure.

B. Swab casing for breakdown, depending on various methods noted.

1. Swab casing dry and spot 300 gals. 7% HCL acid.
2. Swab water off acid and spot 200 gals. of 7% HCL acid.
3. Swab casing dry and clean perforations dry.

C. Breakdown.

1. Start foam at designated rate.
2. Pump for one minute past stablized pressure.
3. Shut-down, observe 30 minute shut-in, calculate bottom hole treating pressure and redesign treatment if necessary

D. Stimulate with Foam-Frac^R as per design.

E. Shut in after treatment.

1. Record shut-in pressures for a minimum of 30 minutes.
2. Rig up flow back apparatus.
    a. Pressure gauge or recorder.
    b. Positive choke with assorted sizes of 6 inch positive bean nipples.
    c. Flow line to tank if liquid recovery is to be measured and recorded.
3. Start flowback immediately if warranted, if not start after fracturing service companies have rigged down and left location.

F. Flowback.

1. Start flowback on 10/64" choke.
2. Record pressures and observations.
3. Change choke sizes depending on flowback response.
4. Flowback overnight.

Third Day

A. Flowback.

1. Continue recording pressures and observations.
2. Measure gas flow rates.
3. Decide if stimulation on next interval uphole can occur the following day.

B. Check casing fillup.

1. Run sinker bar and jars to check PBTD for frac sand fillup.
2. Sand pump if removal of sand from rathole is deemed necessary. Note: This operation may be postponed to the fourth day if the amount of flow makes sand pumping difficult.

Fourth Day

A. Zone isolation.

1. Run in, lubricate if necessary, wireline frac baffle packer and set between zones of interest at 2585-2680'KB and 2500-2757'KB.
2. Exact depth of baffle will depend on casing collars and perforations present and planned.

B. Perforate 2500-2575'KB.

1. Perforate selectively (see First Day #D).
2. Perforate dry.
3. May need to lubricate hollow carrier gun for well control.

C. Breakdown.

1. Drop frac ball and allow to seat.
2. Pump 300 gals. 7% HCL acid.
3. After acid, switch to water and start nitrogen to generate foam.
4. Follow procedure Second Day #C.

D. Stimulate with Foam-Frac[R] as per design.

E. Shut in and flow back is same as on Second Day #E and F.

Fifth Day

A. Flow back as on Third Day #A.

Sixth Day

A. Spud on frac baffle packer and push to bottom.

B. Check final PBTD for fillup.

C. Clean out rathole if necessary.

Seventh Day

A. Repeat Fourth Day thru Sixth Day and continue up hole.

NOTE: The estimated total lapsed completion time is 13 days for four zones, without problems. Recommended time of 17 to 20 days should be planned and budgeted.

Calculations for the pressure drop across limited entry perforations are derived from Bernoull's mass balance. The derived equation is included on two enclosed graphs showing its determinations at various foam rates of 0.7, 0.75, and 0.80 quality foams. The plot shows the pressure drop across one-0.42 in. or one-0.38 in. perforation. This should help determine the number of perforations required for completion.

The pressure drops predicted by this equation are accurate up to 200-300 psid. Above this range, the equation predicts too high a drop for foam. This error in predicting pressure loss becomes critical in the determination of surface treating pressures.

The major effect of high limited entry differentials in this particular well is caused by the relative change in pressure encountered by the foam before entering the perforations. A comparison of data will illustrate:

> Assume 59 bpm of 75 quality foam at 1.25 ppg of sand is needed at 1000 psid fracturing pressure. If the Fracture is 70' high, the calculated width will be 0.203 inches wide and the effective slot viscosity of the foam is 40 cp.

Now note the differences inside the casing, at the perforations if a 0 and 840 psid pressure drop is imposed.

Pressure drop (psid)	0	840	%change
Pressure in casing (psid)	1000	1840	+84
Foam quality	.75	.624	-17
Effective viscosity (cp)	21	17	-19
Sand concentration (ppg)	1.25	1.88	+50

The major effect is two fold, the quality is in a low, unfamiliar range which we attempt to avoid and the sand concentration has increased by 50%.

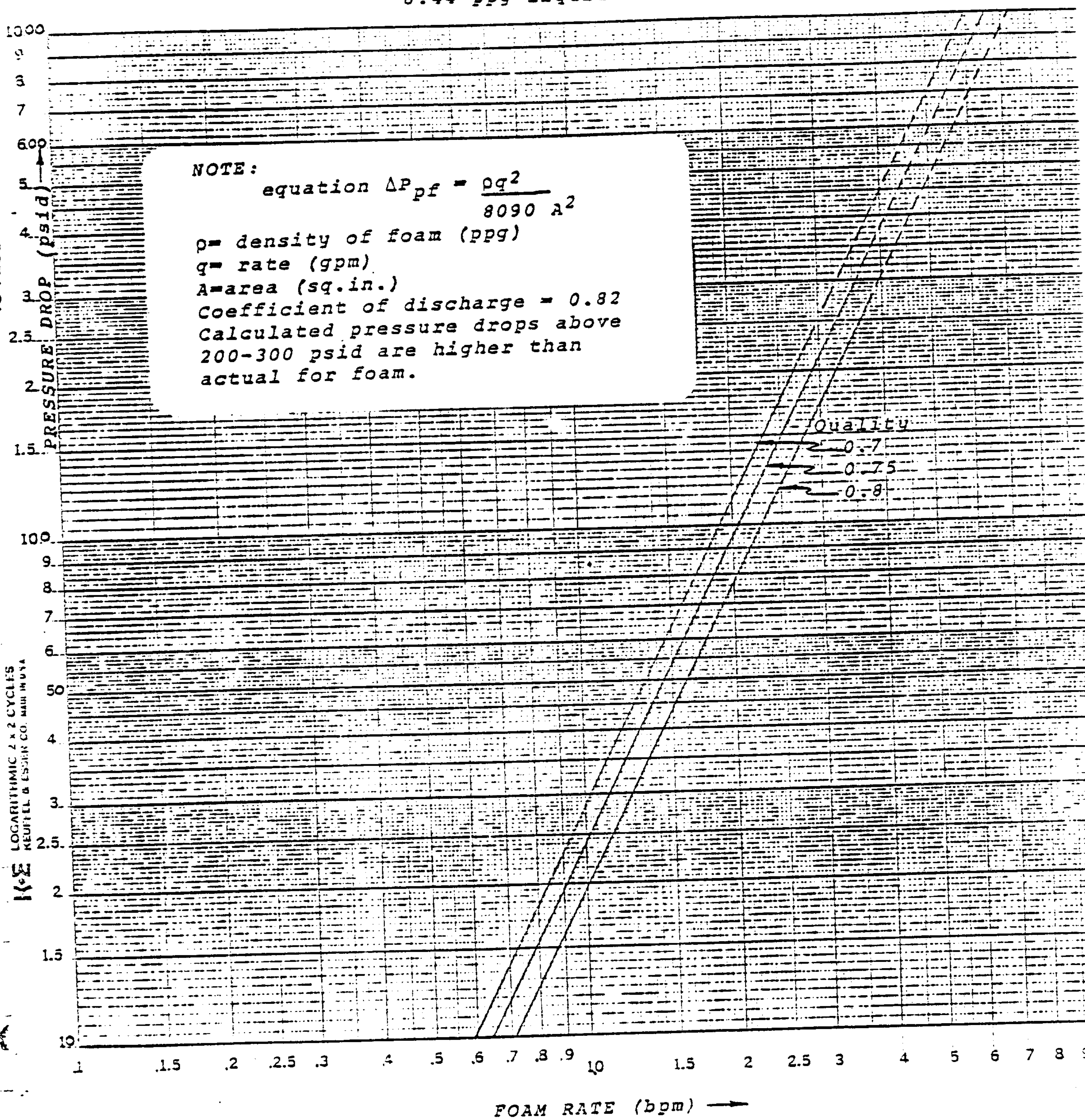
This has not taken into account the possibility of perforations still not opened. At this level, one or two closed perforations will dramatically increase the downhole pressure and result in a screen out!

We have previously used limited entry pressures in the order of 800 psid but in all cases the fracture pressure was 5,000-8,000 psig and the increase did not effect the quality, effective viscosity, or sand concentration to this degree.

The design presented is at 35 bpm with only 200 psid across the perforations. This will allow the first treatment to be accomplished without the above mentioned problem occuring. If the first job is successful, indicating that foam is a viable treatment in this geologic environment we can then increase rates and attempt jobs nearer our original conception.

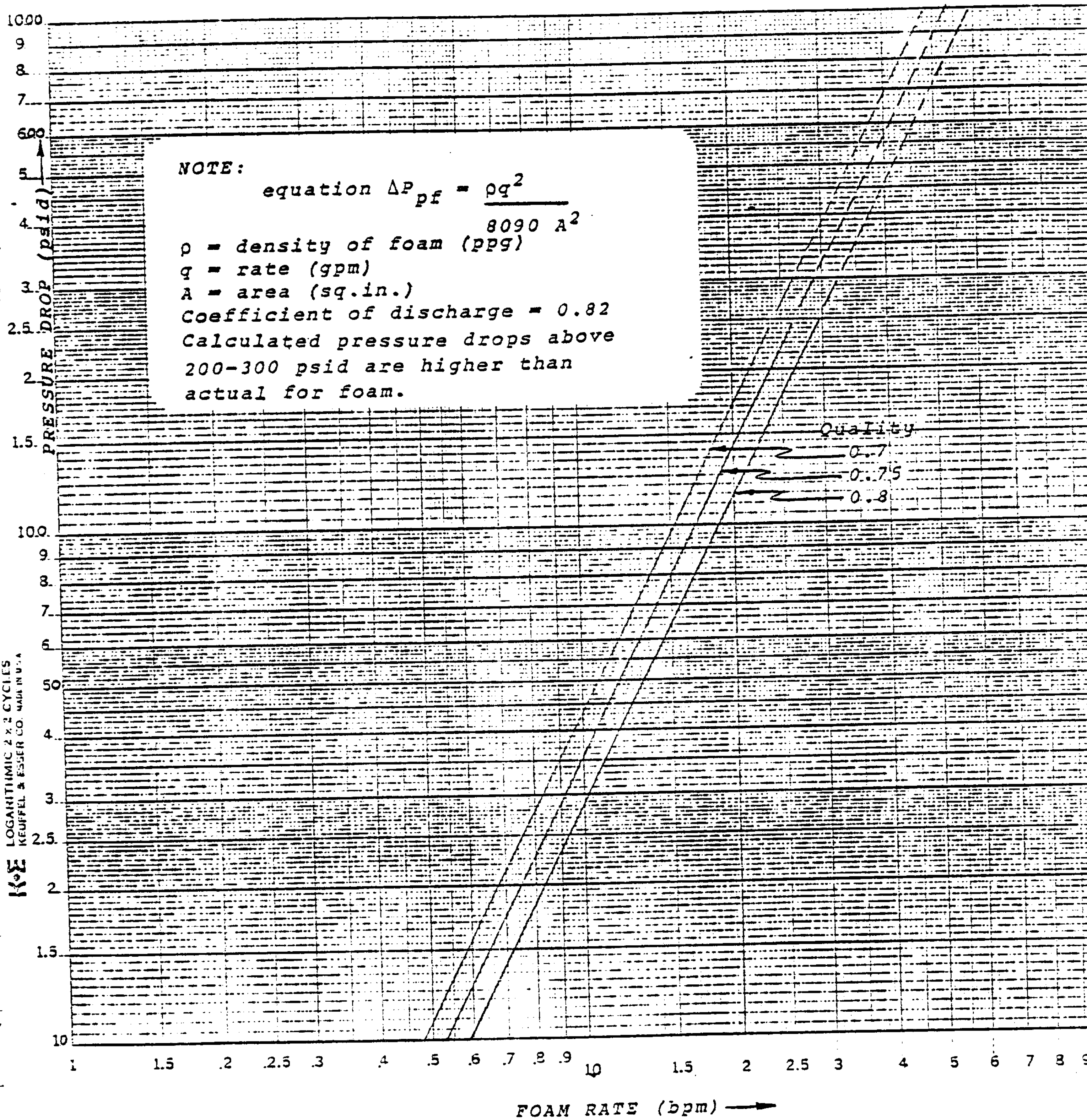
PRESSURE DROP ACROSS ONE PERFORATION AT VARIOUS RATES

0.42 inch Perforation
8.44 ppg liquid base



PRESSURE DROP ACROSS ONE PERFORATION AT VARIOUS RATES

0.38 inch Perforation
8.44 ppg liquid base



WELLHEAD TREATING PRESSURES

Enclosed next are thirteen computer runs calculating wellhead treating pressures using various rates and limited entry perforations. The range of pressures in all cases are well within the safety limits of 4.5 in., 10.5 lb. casing. The data from these calculations are summarized on the following page. The downhole quality is predicted mainly on 1000 psig downhole treating pressure, with other assumptions outlined on the computer printouts. The correct downhole treating pressure will be determined after each respective breakdown just prior to the treatment.

Re: Foam-Frac[R]
Kentucky-West Virginia Gas
#7239 Nicholas-Combs Lease
Hazard Field-Perry County, Kentucky
Zone @ 2585-2680' KB

SUMMARY OF APPENDIX A
WELLHEAD TREATING PRESSURES*

Number #	Bottom-hole Quality	Downhole Foam Rate (bpm)	Wellhead Treating Pressure (psig)	Nitrogen Rate (scfpm)	Water Rate (bpm)	Perforation Size (inches)	No. of Perforations	Pressure Drop Across Perfs (psid)**
1	70	30	1,114	7,523	9.0	infinite		0
2	80	50	1,515	14,330	10.0	infinite		0
3	75	50	1,560	13,435	12.5	infinite		0
4	75	60	2,139	16,122	15.0	0.42	10	863
5	75	60	2,325	16,122	15.0	0.38	10	1,288
6	75	59	2,114	15,853	14.7	0.42	10	834
7	75	59	2,125	15,853	14.7	0.38	12	865
8	75	44.5	1,682	11,957	11.1	0.42	10	475
9	75	44.5	1,812	11,957	11.1	0.38	10	708
10	75	35.0	1,369	9,405	8.7	0.42	12	204
11	75	35.0	1,429	9,405	8.7	0.38	12	304
12	75	30.0	1,236	8,061	7.5	0.42	12	150
13	75	30.0	1,282	8,061	7.5	0.38	12	224

*Note assumptions used on printouts

**Above 250 psid, values may be too large

#1

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

9/24/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680 KB
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	7523.6
BPM REQUIRED	9.0
FOAM FLOW RATE, BPM	30.0
FOAM QUALITY @ BH, %	70.0
INC. LENGTH	1000.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.430

WELL HEAD CSG PSI	11[illegible]4.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRES THE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

#2

4/24/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680 KB
HAZARD FIELD PERRY CO. KY.

BOT. HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	14330.6
BPM REQUIRED	10.0
FOAM FLOW RATE, BPM	50.0
FOAM QUALITY @ BH, %	80.0
INC. LENGTH	100.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.430

WELL HEAD CSG PSI 1515.

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MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

\# 3

4/24/75

KENTUCKY-WEST VIRGINIA GAS
\#7239 NICHOLAS-COMBS LEASE 2585-2630 KB
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI 1000.
DEPTH TO FRACTURE 2640.
SCFM REQUIRED 13434.9 Recommended
BPM REQUIRED 12.5
FOAM FLOW RATE, BPM 50.0
FOAM QUALITY @ BH, % 75.0 @ 900 Psi Bottom Hole Treat
Γ = .768 Rf = 53.81
INC. LENGTH 1000.
O. D. TUBING 0.
I. D. CASING 4.052
B. H. TEMP, F 95.
BASE DENSITY, PPG 8.430

WELL HEAD CSG PSI 1560.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

#4

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	16121.9
BPM REQUIRED	15.0
FOAM FLOW RATE, BPM	60.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	100T.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	10.
DIA. OF PERFS., INCHES	0.420
PRESSURE DROP, PSI	863.
WELL HEAD CSG PSI	2139.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

#5

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	16121.9
BPM REQUIRED	15.0
FOAM FLOW RATE, BPM	60.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	1000.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

59 bpm
@ 12 - 1.38 perfs

NUMBER OF PERFORATIONS	10.
DIA. OF PERFS., INCHES	0.380
PRESSURE DROP, PSI	1283.
WELL HEAD CSG PSI	2325.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

#6

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	15853.2
BPM REQUIRED	14.7
FOAM FLOW RATE, BPM	59.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	1000.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	10.
DIA. OF PERFS., INCHES	0.420
PRESSURE DROP, PSI	834.
WELL HEAD CSG PSI	2114.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

#7

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2580
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	15853.2
BPM REQUIRED	14.7
FOAM FLOW RATE, BPM	59.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	100.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.400

NUMBER OF PERFORATIONS	12.
DIAM. OF PERFS., INCHES	0.380
PRESSURE DROP, PSI	865.
WELL HEAD CSG PSI	2125.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75 #8

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	10[illegible].
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	1[illegible]957.1
BPM REQUIRED	11.1
FOAM FLOW RATE, BPM	44.5
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	100[illegible].
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440
NUMBER OF PERFORATIONS	10.
DIA. OF PERFS., INCHES	0.420
PRESSURE DROP, PSI	475.
WELL HEAD CSG PSI	1682.

#perfs	ΔP_{pf}
15	211
14	242
13	281
12	330
11	392
10	475
9	586
8	742
7	963

$Q_F = 33.467$
$\rho = \cancel{.663}$ .6715
$\mu_c \approx 20cp$

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/10/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680 #9
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	11957.1
BPM REQUIRED	11.1
FOAM FLOW RATE, BPM	44.5
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	1000.
O. D. TUBING	0.
I. D. CASING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	10.
DIA. OF PERFS., INCHES	0.380
PRESSURE DROP, PSI	708.
WELL HEAD CSG PSI	1812.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/16/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

#10

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	9404.5
BPM REQUIRED	8.7
FOAM FLOW RATE, BPM	35.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	1000.
I. D. TUBING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	12.
DIA. OF PERFS., INCHES	0.420
PRESSURE DROP, PSI	204.
WELL HEAD TBG PSI	1369.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

10/16/75

#11

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	9404.5
BPM REQUIRED	8.7
FOAM FLOW RATE, BPM	35.0
FOAM QUALITY @ BH, %	75.0
TBG. LENGTH	1000.
I. D. TUBING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	12.
DIA. OF PERFS., INCHES	0.380
PRESSURE DROP, PSI	304.

2640.	1304.	93.	1.007	20.282	0.694	30.5	34.342	35.197	2.544	0.051
1640.	1351.	87.	1.007	19.351	0.683	29.3	33.654	35.492	2.630	0.041
640.	1396.	83.	1.006	18.574	0.680	28.6	32.852	35.479	2.702	0.032
0.	1429.	80.	1.006	18.041	0.673	28.0	32.075	35.275	2.757	0.026

WELL HEAD TBG PSI 1429.

FOAM FRAC IS A REGISTERED TRADE MARK
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MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

#12

10/16/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	1000.
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	8061.0
BPM REQUIRED	7.5
FOAM FLOW RATE, BPM	30.0
FOAM QUALITY @ BH, %	75.0
INC. LENGTH	100.
I. D. TUBING	4.052
B. H. TEMP, F	93.
BASE DENSITY, PPG	8.440
NUMBER OF PERFORATIONS	12.
DIA. OF PERFS., INCHES	0.420
PRESSURE DROP, PSI	150.
WELL HEAD TBG PSI	1235.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

MINERALS MANAGEMENT INC.
DENVER, COLORADO
FOAM FRAC(TM) WELL HEAD PRESSURE PREDICTION
USING THE METHOD OF BLAUER, MITCHELL & KOHLHAAS

#13

10/16/75

KENTUCKY-WEST VIRGINIA GAS
#7239 NICHOLAS-COMBS LEASE 2585-2680
HAZARD FIELD PERRY CO. KY.

BOT.-HOLE FRAC. PSI	10[illegible].
DEPTH TO FRACTURE	2640.
SCFM REQUIRED	8061.0
BPM REQUIRED	7.5
FOAM FLOW RATE, BPM	30.0
FOAM QUALITY @ BH, %	75 0
INC. LENGTH	10[illegible].
I. D. TUBING	4.052
B. H. TEMP, F	43.
BASE DENSITY, PPG	8.440

NUMBER OF PERFORATIONS	12.
DIA. OF PERFS., INCHES	0.380
PRESSURE DROP, PSI	2[illegible]4.
WELL HEAD TBG PSI	1282.

FOAM FRAC IS A REGISTERED TRADE MARK
OF MINERALS MANAGEMENT INC.

FOAM-FRAC $_{TM}$ SERVICE

Minerals Management, Inc., offers unit responsibility when fracturing a well with foam - from initial technical sales presentation thru final report and invoice for the total job. Minerals Management, Inc., alone has designed all successful Foam-Frac's $_{TM}$ to date. This experience and expertise is applied throughout our FOAM-FRAC $_{TM}$ SERVICE which includes:

- Initial technical presentation
- Initial cost estimates
- Total engineering of the frac treatment
- Coordination and contracting nitrogen, pumping trucks, surfactant, propping agent
- On site supervision by Minerals Management, Inc., field engineer to assure frac is performed as designed
- Minerals Management, Inc., supervisor in charge assures unit responsibility for the total effort
- Final report and invoice

Our goal is to provide our client the best, most profitable well stimulation possible with FOAM-FRAC $_{TM}$.

FOAM-FRAC$_{TM}$ - FEE SCHEDULE

\$ 6,000 or less	\$ 600.00 Minimum
\$ 6,000 - 17,000	\$ 600.00 + 7.5% in excess of \$6,000
\$17,000 - 25,000	\$1,425.00 + 6% in excess of \$17,000
\$25,000 and up	\$1,905.00 + 3% in excess of \$25,000

MINERALS MANAGEMENT, INC.
April 24, 1974

Exhibit II

ALLEGHENY NUCLEAR SURVEYS, Inc.

WESTON, WEST VIRGINIA

RADIOACTIVITY LOG

FILING NO	KENTUCKY W. VA. GAS NICHOLAS COMBS WELL NO. 7239 PERMIT # 28982
COMPANY	KENTUCKY WEST VIRGINIA GAS COMPANY
WELL	NICHOLAS COMBS WELL NO. 7239
FIELD	HAZARD
COUNTY	PERRY
STATE	KENTUCKY
LOCATION	N. 155.98, E. 188.65 ON WATERS OF BOWMAN BR. OF LOST CREEK.
SEC / TWP / RGE	
OTHER SERVICES	JET PERF.
PERMANENT DATUM	GROUND LEVEL, ELEV 1079.60
LOG MEASURED FROM	10 FT ABOVE PERM. DATUM
DRILLING MEASURED FROM	KELLY BUSHING
ELEV K.B	1089.60
D.F	-
G.L	1079.60

DATE	10/29/75	10/29/75	
RUN NO	ONE	TWO	
TYPE LOG	GAMMA CORR.	CEM.QUAL.	
DEPTH-DRILLER	2696	2696	
DEPTH-LOGGER	2697	2697	
BOTTOM LOGGED INTERVAL	2696	2696	
TOP LOGGED INTERVAL	1600	1600	
TYPE FLUID IN HOLE	WATER	WATER	
SALINITY, PPM CL	-	-	
DENSITY	-	-	
LEVEL	N/A	N/A	
MAX REC TEMP DEG F	-		
OPERATING RIG TIME	-		
RECORDED BY	HARLESS		
WITNESSED BY	MR.HAGER	MR.PAUGHN	

RUN NO	BORE HOLE RECORD BIT	FROM	TO	CASING RECORD SIZE	WGT	FROM	TO
				4½	-	SURFACE	T.D.

FOLD HERE

THIS HEADING AND LOG CONFORMS TO API RP 33

EQUIPMENT DATA

GAMMA RAY			NEUTRON		
RUN NO	I		RUN NO.		
TOOL MODEL NO.	GCN 56X		LOG TYPE	NN	
DIAMETER	3.5"		TOOL MODEL NO.	GCN 56X	
DETECTOR MODEL NO.	A.P.A.		DIAMETER	3.5"	
TYPE	SCINT.		DETECTOR MODEL NO.	SPG4	
LENGTH	3"		TYPE	SCINT.	
DISTANCE TO N. SOURCE	108"		LENGTH	1"	
			SOURCE MODEL NO.		
GENERAL			SERIAL NO.		
HOIST TRUCK NO.	309		SPACING	7.5	
INSTRUMENT TRUCK-NO	309		TYPE		
TOOL SERIAL NO.			STRENGTH		

LOGGING DATA

RUN NO.	DEPTHS FROM	TO	SPEED FT./MIN	T.C SEC.	SENS SETTINGS	ZERO DIV L OR R	API G.R. UNITS PER LOG DIV.	T.C. SEC.	SENS. SETTINGS	ZERO DIV L OR R	API N. UNITS PER LOG DIV.
I	2696	I600	30	3	300	0 - L	20				
2	2696	I600	30	3	400	CEMENT QUALITY					

REFERENCE LITERATURE:

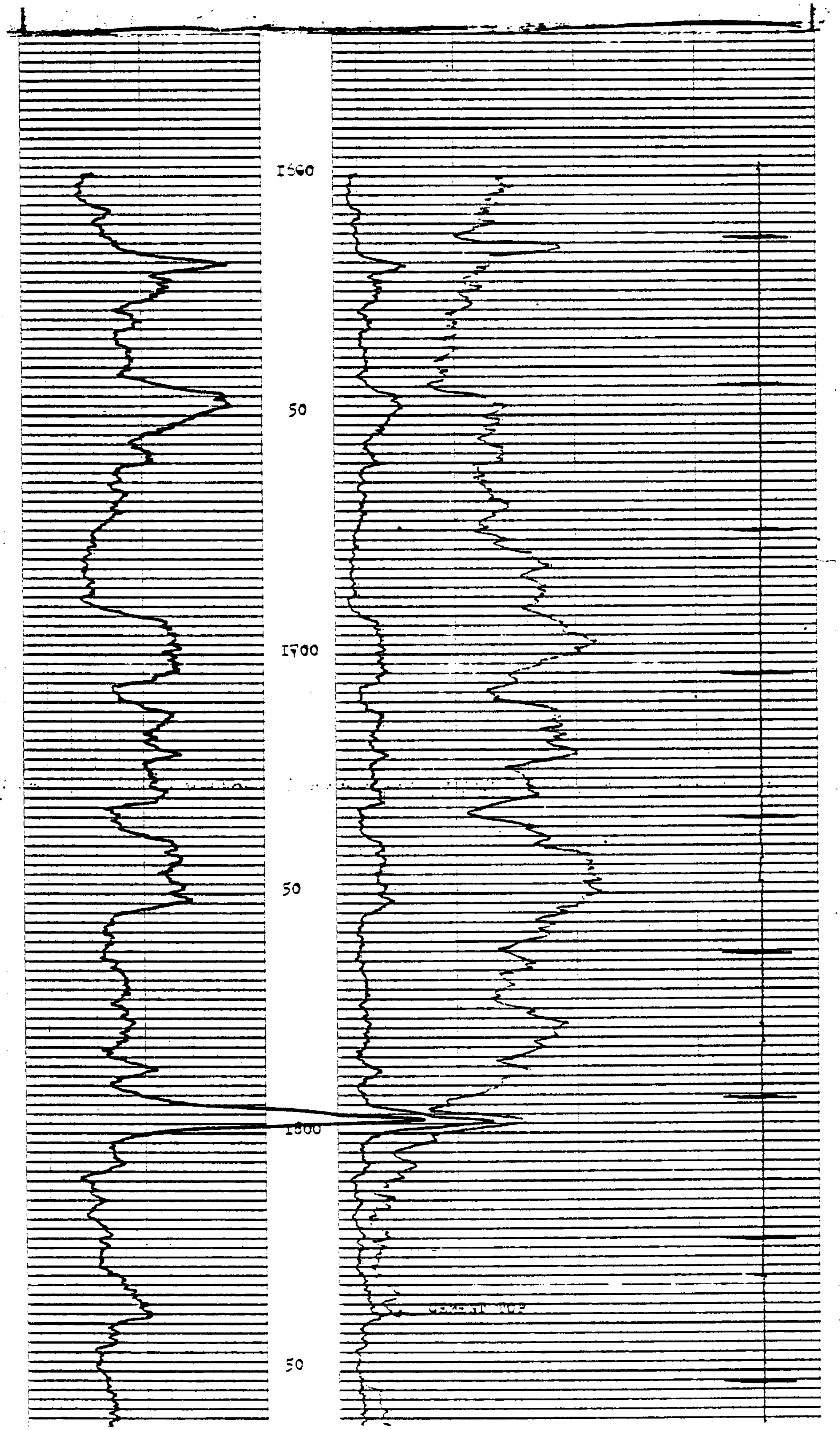
REMARKS

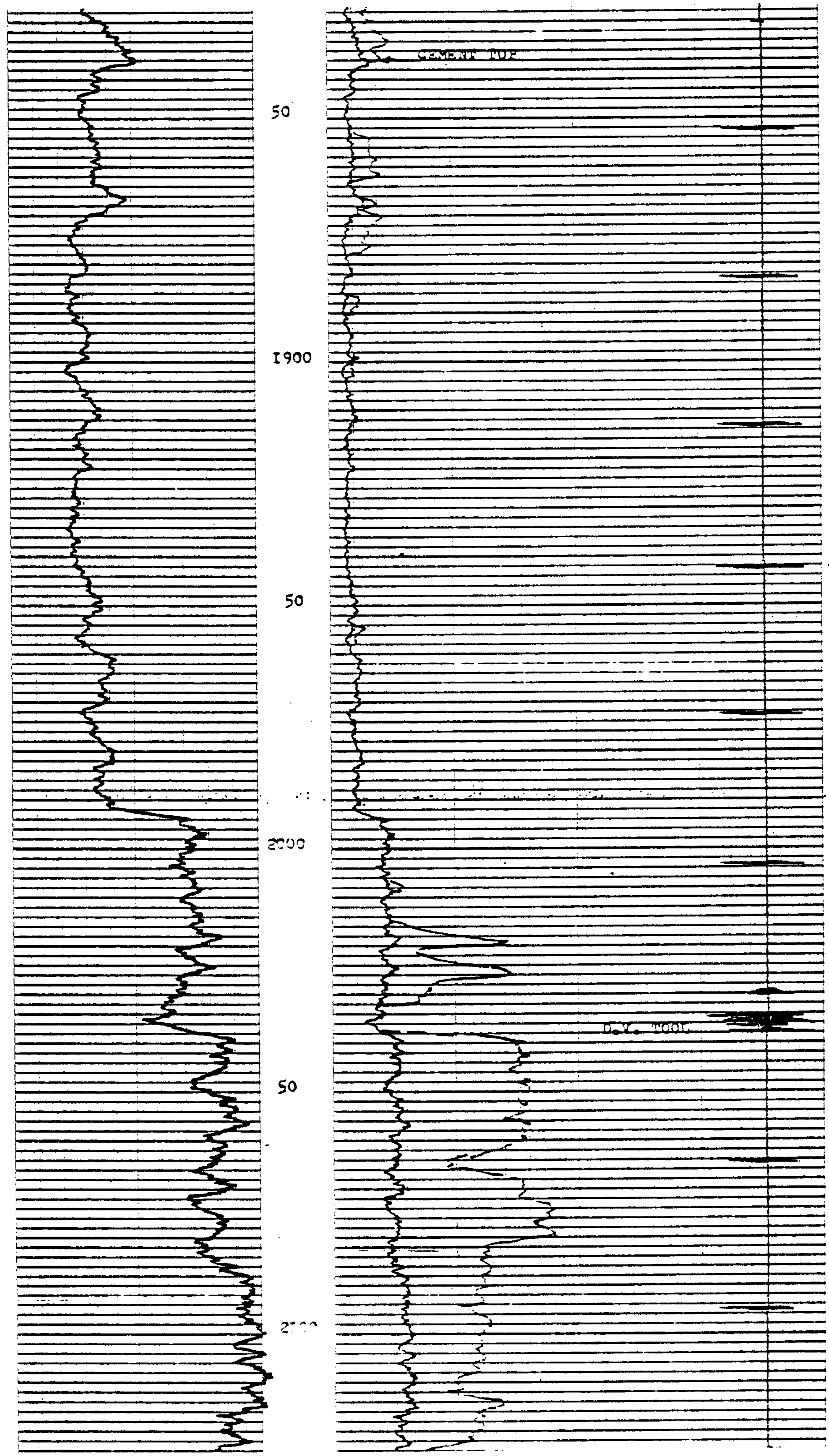
GAMMA RAY
API UNITS

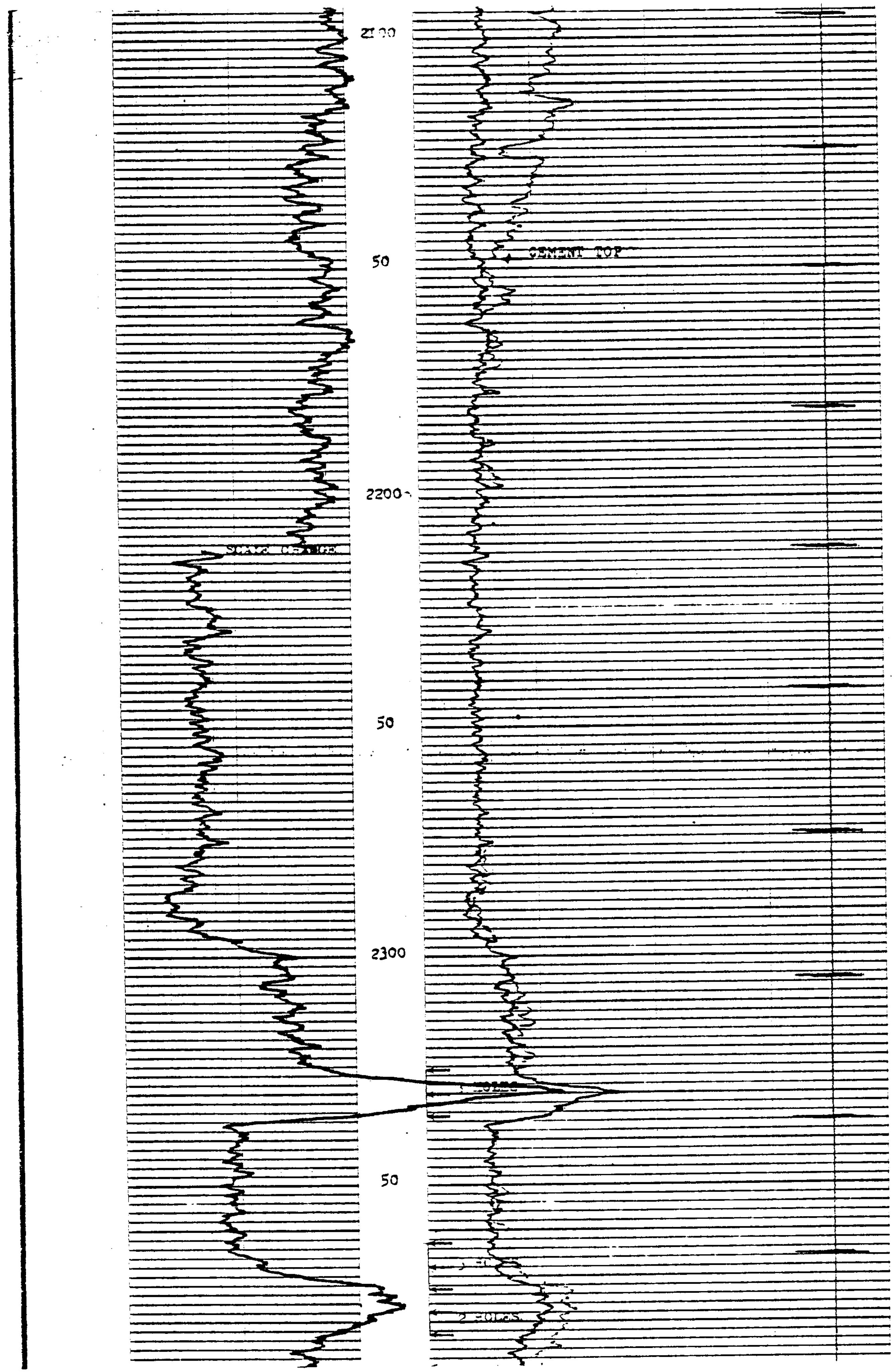
DEPTH AND CASING COLLARS

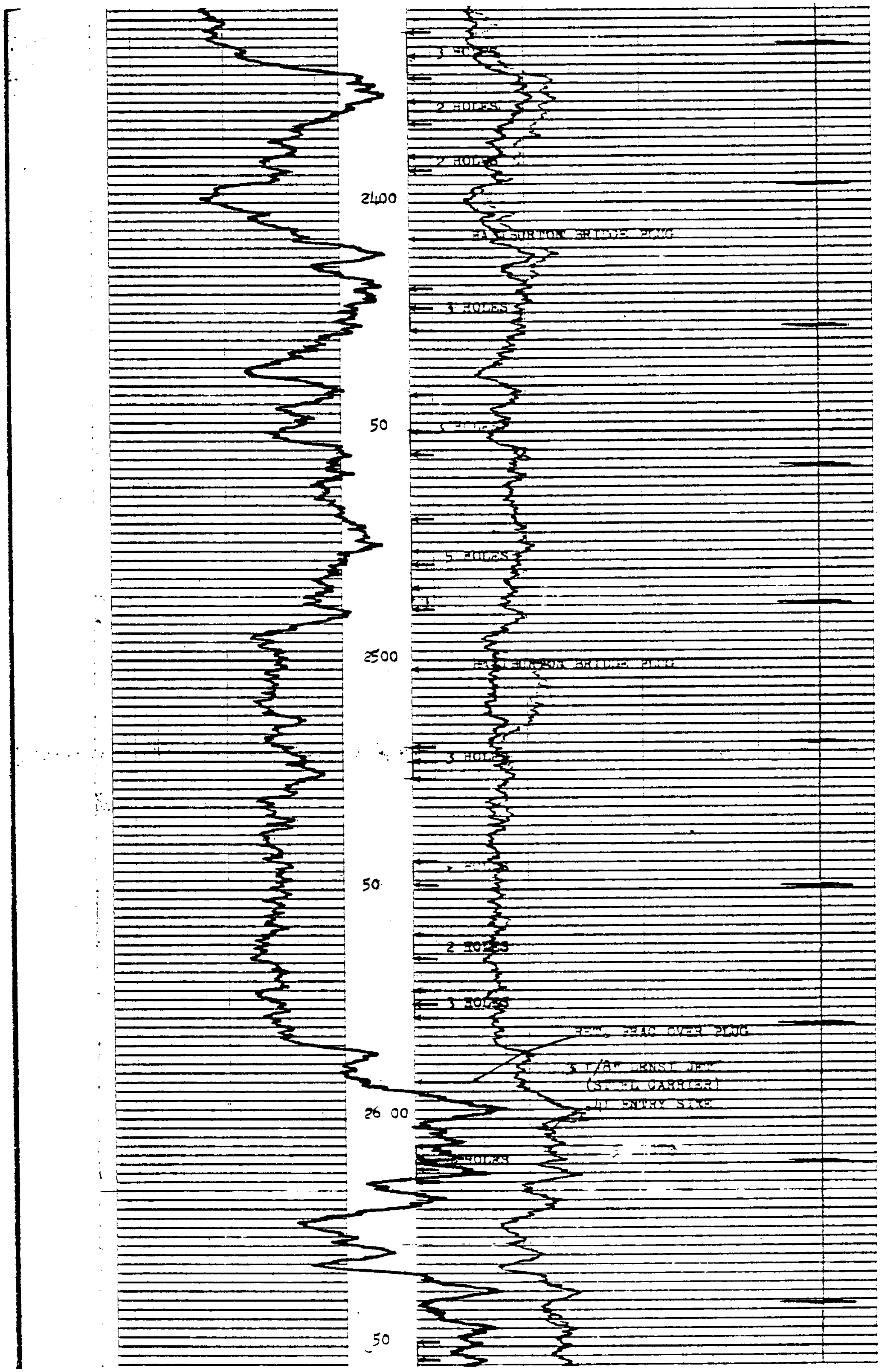
NEUTRON
API UNITS

30


1600
50
1700
50
1800
CEMENT TOP
50


CEMENT TOP
50
1900
50
2000
D.V. TOOL
50


2100
50
CEMENT TOP
2200
SCALE CHANGE
50
2300
50



2 HOLES
2400
3 HOLES
50
5 HOLES
2500
3 HOLES
50
2 HOLES
3 HOLES
2600
50

34

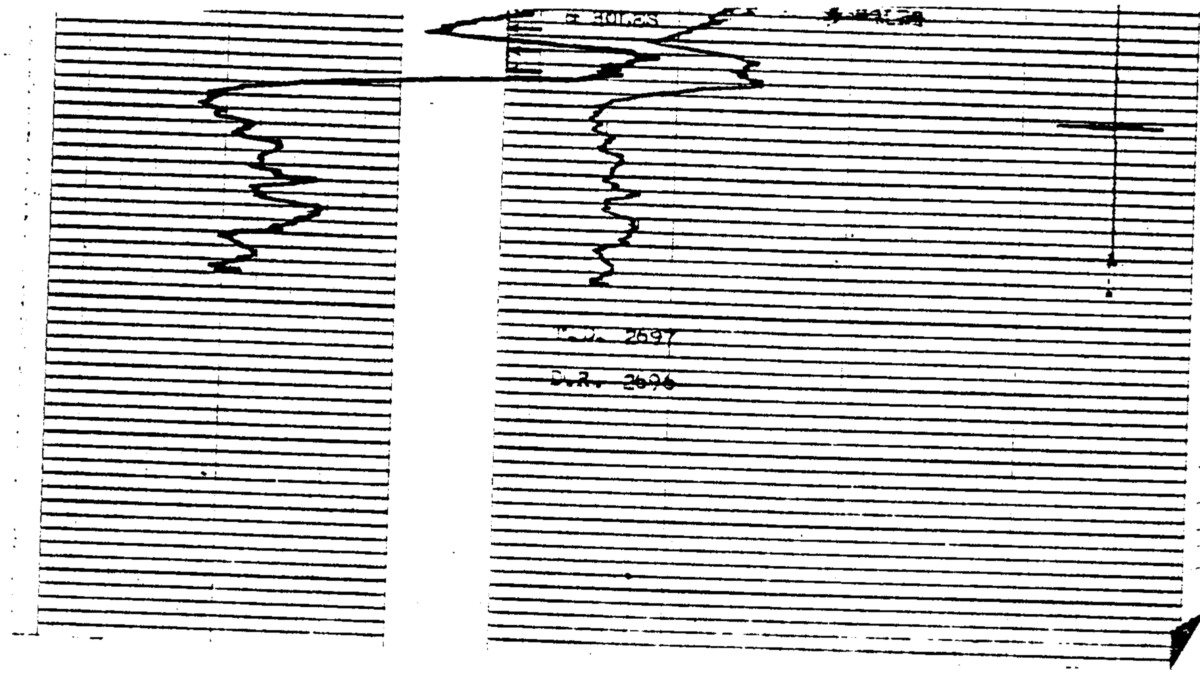

2697
2696

Exhibit III

ALLEGHENY NUCLEAR SURVEYS, Inc.

WESTON, WEST VIRGINIA

RADIOACTIVITY LOG

FILING NO

KENTUCKY W. VA. GAS
NICHOLAS COMBS
WELL NO. 7239
PERMIT # 28982

COMPANY KENTUCKY WEST VIRGINIA GAS COMPANY

WELL NICHOLAS COMBS WELL NO. 7239

FIELD HAZARD

COUNTY PERRY STATE KENTUCKY

LOCATION N.155.98 E.188.65 ON WATERS OF BOWMAN BR. OF LOST CREEK.

SEC TWP RGE

OTHER SERVICES

PERMANENT DATUM GROUND LEVEL ELEV 1079.60

LOG MEASURED FROM 10 FT ABOVE PERM DATUM

DRILLING MEASURED FROM KELLY BUSHING

ELEV KB 1089.60
DF -
GL 1079.60

DATE	11/25/75	
RUN NO	ONE	
TYPE LOG	GAMMA RAY	(FOR TRACER SURVEY)
DEPTH - DRILLER	2673	
DEPTH - LOGGER	2673	
BOTTOM LOGGED INTERVAL	2665	
TOP LOGGED INTERVAL	2300	
TYPE FLUID IN HOLE	FOAM	
SALINITY, PPM CL	-	
DENSITY	-	
LEVEL	N/A	
MAX REC TEMP DEG F	-	
OPERATING RIG TIME	1 HOUR	
RECORDED BY	HARLESS	
WITNESSED BY	MR. HAGER	

RUN NO	BORE HOLE RECORD: BIT	FROM	TO	CASING RECORD: SIZE	WGT	FROM	TO
				4½	-	SURFACE	T.D.

FOLD HERE

THIS HEADING AND LOG CONFORMS TO API RP 33

EQUIPMENT DATA

GAMMA RAY			NEUTRON		
RUN NO.	I		RUN NO.		
TOOL MODEL NO	GCN 56X		LOG TYPE	NN	
DIAMETER	3.5"		TOOL MODEL NO.	GCN 55X	
DETECTOR MODEL NO	APA		DIAMETER	3.5"	
TYPE	SCINT		DETECTOR MODEL NO.	SPG4	
LENGTH	3"		TYPE	SCINT	
DISTANCE TO N. SOURCE	108"		LENGTH	1"	
			SOURCE MODEL NO.		
GENERAL			SERIAL NO.		
HOIST TRUCK NO	309		SPACING	[illegible]	
INSTRUMENT TRUCK NO	309		TYPE		
TOOL SERIAL NO			STRENGTH		

LOGGING DATA

RUN NO.	DEPTHS FROM	DEPTHS TO	SPEED FT/MIN	GAMMA RAY T.C. SEC	SENS SETTINGS	ZERO DIV L OR R	API G.R. UNITS PER LOG DIV	NEUTRON T.C. SEC.	SENS. SETTINGS	ZERO DIV L OR R	API N. UNITS PER LOG DIV
I	2665	2300	30	3	55	0 - L	20				

REFERENCE LITERATURE:

REMARKS

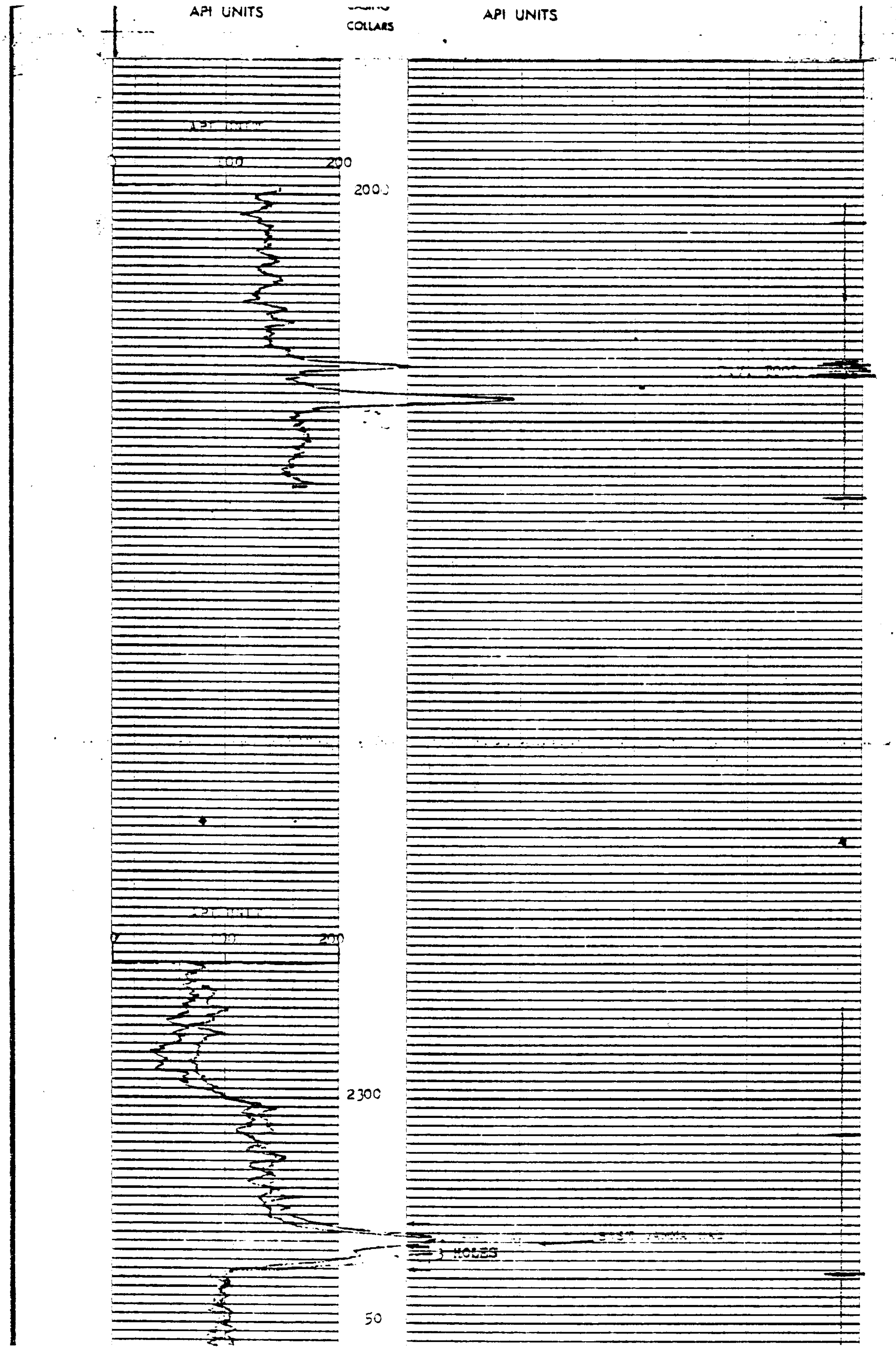
GAMMA RAY

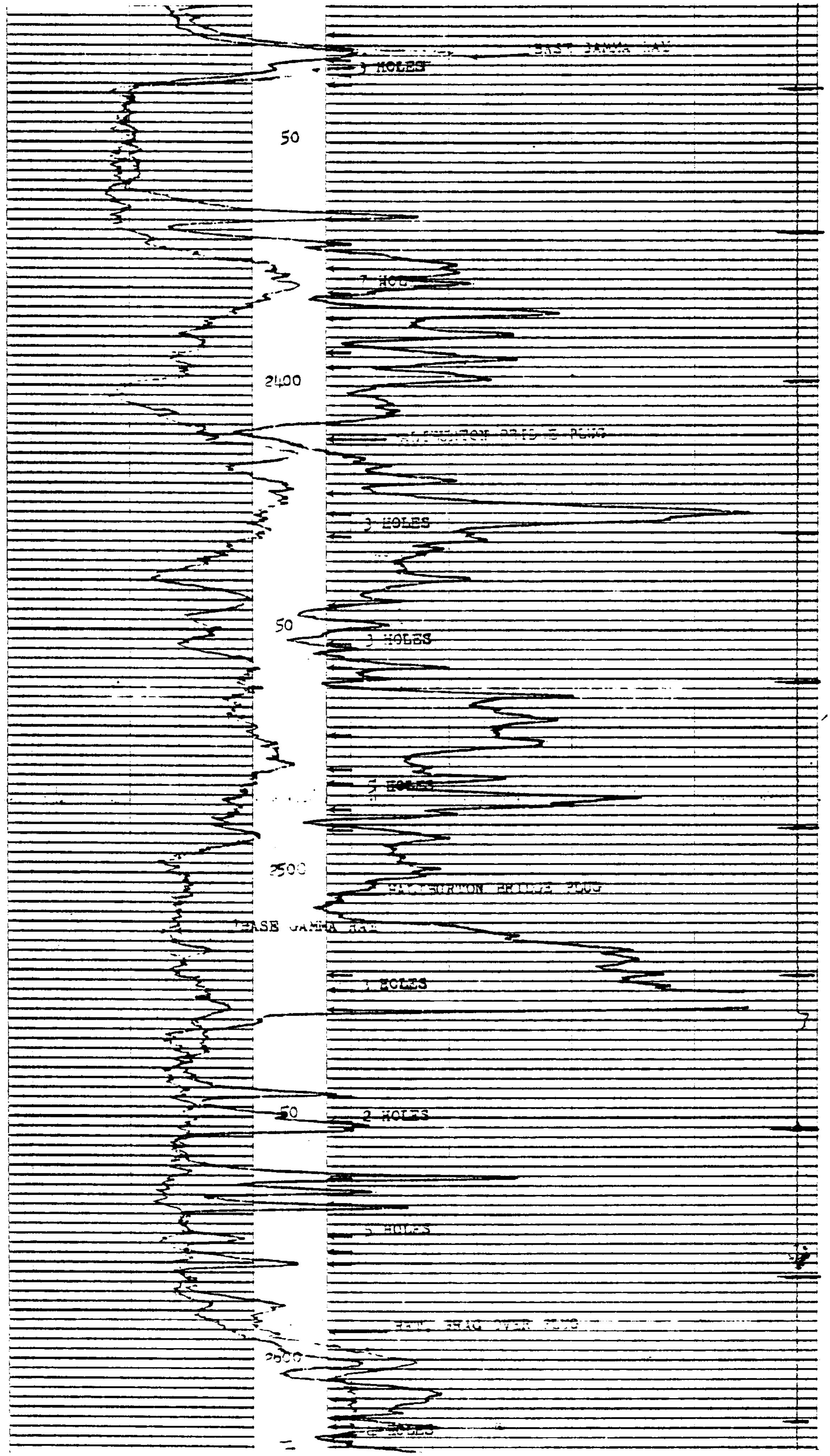
API UNITS

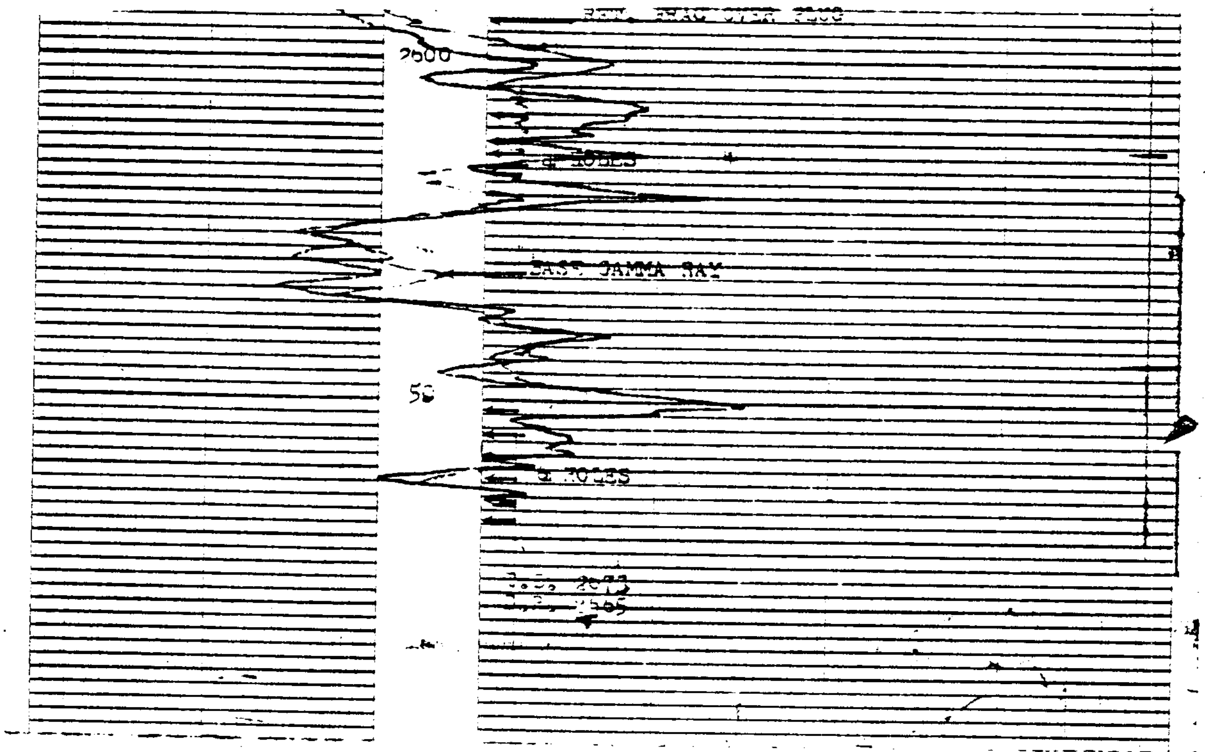
DEPTH AND CASING COLLARS

API UNITS

2300


API UNITS
COLLARS
API UNITS
200
2000
200
2300
3 HOLES
50


3 HOLES
50
2400
3 HOLES
50
3 HOLES
2500
2 HOLES


2600
BASE GAMMA RAY